BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2021-89-E
DOCKET NO. 2021-90-E

In the Matter of:	)	
	)	
Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's 2021 Avoided Cost Proceeding Pursuant to S.C. Code Ann. Section 58-41-20(A)	))))))	**DIRECT TESTIMONY OF GLEN A. SNIDER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Duke Energy as Director of Carolinas Integrated Resource Planning and Analytics.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DUKE ENERGY.

A. I am responsible for the supervision of the Integrated Resource Plans ("IRPs") for both Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies"). In addition to the production of the IRPs, I have responsibility for overseeing the analytic functions related to resource planning for the Carolinas region. Examples of such analytic functions include unit retirement analyses, the analytical support for applications for certificates of environmental compatibility and public convenience and necessity for new generation, and analyses required to support the Companies' avoided cost calculations that are used in the biennial avoided cost rate proceedings.

I have extensive experience with the federal regulatory framework implementing Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including the Federal Energy Regulatory Commission's ("FERC") implementing regulations, and I am also familiar with the history of PURPA implementation in South Carolina, including the Commission's recent PURPA implementation under the South Carolina Energy Freedom Act of 2019 ("Act 62" or the "Act"). I previously testified in the Companies' initial 2019 avoided cost proceedings to implement the PURPA provisions of Act 62 (in Docket Nos. 2019-185-E and 2019-186-E) ("2019 Avoided Cost Proceeding"). I have also been involved in numerous PURPA implementation proceedings in the Companies' North Carolina jurisdiction dating back to 2012.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. My educational background includes a Bachelor of Science in mathematics and a Bachelor of Science in economics from Illinois State University. With respect to professional experience, I have been in the utility industry for over thirty years. I started as an associate analyst with the Illinois Department of Energy and Natural Resources, responsible for assisting in the review of Illinois utilities' integrated resource plans. In 1992, I accepted a planning analyst job with Florida Power Corporation and for the past twenty years have held various management positions within the utility industry. These positions have included managing the Risk Analytics group for Progress Ventures and the Wholesale Transaction Structuring group for ArcLight Energy Marketing. Immediately prior to the merger of Duke Energy Corporation and Progress Energy, I was Manager of Resource Planning for Progress Energy Carolinas. From 2012 to present I have held the position of Director of Resource Planning and Analytics for DEC and DEP.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA?

A. Yes. I have testified before the Commission on a number of occasions. Most recently I testified in the Companies' IRP proceedings in Docket Nos. 2019-224-E and 2019-225-E.

Q. ARE YOU INCLUDING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I am sponsoring one exhibit for DEC and DEP, respectively, and two DEC/DEP joint exhibits, which are described below:

- **Snider DEC Exhibit 1 (Confidential)** presents the supporting calculations used to derive the avoided energy and avoided capacity rates. Certain information included in this exhibit is designated Confidential and is being filed under seal.[1]
- **Snider DEP Exhibit 1 (Confidential)** presents the supporting calculations used to derive the avoided energy and avoided capacity rates. Certain information included in this exhibit is designated Confidential and is being filed under seal.
- **Snider DEC/DEP Exhibit 2** presents additional analytical support for the avoided energy and avoided capacity cost rate periods, as directed in Order 2019-881(A).

[1] The information contained in Snider DEC Exhibit 1 and Snider DEP Exhibit 1 was filed with the Companies' Application in these dockets on April 22, 2021, and the Companies' request for confidentiality was approved by the Commission in Order 2021-54-H.

- **Snider DEC/DEP Exhibit 3** presents figures that demonstrate the avoided energy and avoided capacity rate design pricing periods.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared by me or at my direction and under my supervision.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support the Companies' implementation of the requirements of the PURPA and the PURPA-related sections of Act 62, including the methodology for calculating avoided cost rates paid to Qualifying Facilities ("QFs") pursuant to these laws. More specifically, my testimony provides recommendations relating to the fair and appropriate calculation of avoided capacity and avoided energy costs used to compensate QFs under the Companies' Standard Offer Purchased Power Tariff ("Standard Offer Tariff" or "Schedule PP") and Large QF Tariff.

My testimony is organized into the following sections:

I. Introduction and Purpose;
II. Overview of PURPA and Act 62 Avoided Cost Framework;
III. Description of the Peaker Methodology used to Calculate Avoided Costs under PURPA;
IV. Avoided Capacity Cost Calculation and Rate Design Methodology; and
V. Avoided Energy Cost Calculation and Rate Design Methodology.

II. OVERVIEW OF PURPA AND ACT 62 AVOIDED COST FRAMEWORK

Q. PLEASE PROVIDE THE COMMISSION WITH A GENERAL EXPLANATION OF PURPA AND ITS ORIGINAL PURPOSE.

A. While I am not an attorney, I have had occasion to become familiar with Section 210 of PURPA and the FERC regulations implementing PURPA through my role with the Companies.

PURPA was enacted in 1978 in response to the mid-1970s energy crisis, to promote conservation of oil and natural gas by electric utilities, thereby lessening the country's dependence on foreign oil, and ultimately intending to control costs for consumers. As I explain further below in my testimony, PURPA requires electrical utilities to purchase the output of QFs at a cost not to exceed the utility's "incremental cost of alternative energy" or, as defined by the FERC in its 1980 rulemaking order to implement PURPA, Order No. 69, the utility's "avoided cost."[2] This is often called the "mandatory purchase obligation," as it requires utilities to purchase all of the output of these facilities at the QF's election.

Q. PLEASE EXPLAIN THE ROLE OF FERC AND THE ROLE OF THIS COMMISSION IN IMPLEMENTING PURPA.

A. Congress gave important roles to both FERC and to state regulatory commissions in implementing PURPA. Congress directed FERC to promulgate regulations to implement PURPA, while state regulatory authorities, such as this Commission, are

[2] *See* 16 U.S.C. § 824a-3(a), (d); 18 C.F.R. 292.304(a); *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (1980) ("Order No. 69").

ultimately responsible for state-by-state PURPA implementation in a manner consistent with FERC's regulations.[3]

Q. PLEASE PROVIDE THE COMMISSION AN OVERVIEW OF ACT 62 AS IT RELATES TO SOUTH CAROLINA'S IMPLEMENTATION OF PURPA AND THE PURPOSE OF THIS PROCEEDING.

A. On May 16, 2019, Act 62 was signed into law, which, in part, addresses South Carolina's implementation of PURPA. Relevant to this proceeding, Act 62 enacted South Carolina Code Section 58-41-20(A), which requires the Commission, on a biennial basis, to approve each electrical utility's PURPA implementation framework, specifically including its avoided cost methodology and the contracting documents used when transacting with small power producer QFs under PURPA. My testimony focuses on the avoided cost methodology and the resulting avoided energy and avoided capacity rates. DEC/DEP Witness David Johnson's testimony focuses on the contracting documents.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN "SMALL POWER PRODUCERS," AS SPECIFICALLY ADDRESSED IN ACT 62, AND "QUALIFYING FACILITIES," WHICH PURPA REGULATES.

A. The requirements of PURPA apply to all QFs, which are comprised of two classes of generators: (1) cogeneration facilities meeting certain operational and efficiency requirements and (2) facilities defined as "small power producers."[4] The South

[3] *Policy Statement Regarding Comm'n's Enforcement Role Under Sec. 210 of the Public Utility Regulatory Policies Act of 1978*, 23 FERC ¶ 61,304, 61,644 (1983) (stating how state regulatory authorities are required to implement PURPA pursuant to section 210 either (1) through enactment of laws or regulations; (2) by application on a case-by-case basis; or, (3) by any other action reasonably designed to implement FERC's PURPA regulations).

[4] 18 C.F.R. § 292.201-205.

Carolina General Assembly was specific that the Commission's implementation of PURPA applies specifically to "small power producers," as that term is defined in federal law.[5] Small power production facilities are defined as facilities which use biomass, waste, or renewable resources, including solar energy, wind energy or water, to produce electric power, and which, together with other facilities at the same site, have a generating capacity equal to or less than 80 megawatts ("MW").[6] Importantly, while the General Assembly's focus in Act 62 is on small power producers, the mandatory purchase requirements of PURPA extend to all QFs, not just small power producers. Therefore, the Companies are making their Standard Offer Tariffs available to all QFs in compliance with PURPA and FERC's regulations.

Q. UNDER PURPA'S "MANDATORY PURCHASE OBLIGATION," IS THERE A LIMIT ON THE TOTAL AMOUNT OF POWER THAT THE COMPANIES MUST PURCHASE FROM QFs?

A. No. The utility is obligated to purchase power from every QF that commits itself to sell to the utility at the utility's avoided cost. However, as I explain further below, the Commission must ensure that the rates for purchase from QFs remain just and reasonable to the utility and do not exceed the utility's avoided cost, which may change over time as the utility's costs of purchasing power changes.[7]

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[5] S.C. Code Ann. § 58-41-10(14).
[6] 18 C.F.R. § 292.204.
[7] 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304(a).

Q. WHO PAYS FOR ALL OF THE POWER THAT PURPA REQUIRES THE COMPANIES TO PURCHASE FROM QFS?

A. The Companies' customers pay for all purchases of QF power. The costs of QF power are a wholesale purchased power expense that is simply passed through to customers under the Companies' fuel clause.

Q. HOW MANY MEGAWATTS OF QF POWER ARE THE COMPANIES CURRENTLY OBLIGATED TO PURCHASE PURSUANT TO PURPA?

A. As of May 17, 2021, the Companies have over 4,700 MW of QF PURPA power under contract on a system-wide basis (including purchases from QFs interconnected and delivering power to the DEC and DEP systems in South Carolina and North Carolina), with the significant majority of these QF purchase obligations being in DEP.

Q. GIVEN THAT CUSTOMERS ARE RESPONSIBLE FOR ALL COSTS ASSOCIATED WITH THESE PURCHASES, HOW DID CONGRESS AND FERC DESIGN PURPA TO PROTECT RATEPAYERS?

A. In enacting Section 210 of PURPA, Congress expressly focused on controlling costs for consumers, requiring utilities to purchase power from QFs at rates that are just and reasonable to the utility's customers and in the public interest.[8] Congress specifically directed FERC to develop regulations to implement PURPA, but, in doing so, explicitly forbade such rules from requiring a utility to pay a rate that would exceed the utility's "incremental cost" of its alternative options of generating

[8] 16 U.S.C § 824a-3(b)(1).

or purchasing electric energy.[9] Congress was clear that PURPA was not intended to require the ratepayers of a utility to subsidize QFs.[10] Accordingly, PURPA limits the rates to be paid to QFs to the purchasing utility's incremental or "avoided" cost, which is designed to ensure customers remain indifferent between the costs of utility or non-utility generation and, thereby, prohibits unjustly subsidizing QFs by paying rates that exceed avoided costs.[11]

Q. DOES ACT 62 ALSO ADDRESS CONGRESS' ORIGINAL CONCERN IN ENACTING PURPA OVER THE COSTS THAT CONSUMERS SHOULD BEAR FROM PURCHASING QF POWER?

A. Yes. Act 62 goes even further than Congress or FERC in this regard, and specifically requires that the Commission's decisions in adjudicating this proceeding must "strive to reduce the risk placed on the using and consuming public."[12]

Q. DOES THE DEFINITION OF AVOIDED COST IN ACT 62 ALIGN WITH THE GENERAL REQUIREMENTS OF PURPA?

A. Yes, Act 62 defines "avoided cost" as:

> . . . the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from

[9] 16 U.S.C § 824a-3(b), (d).

[10] Joint Explanatory Statement of the Committee of Conference, H.R. Conf. Rep. 95-1750 at p. 89, 95th Cong., 2d. Sess. 99 (1978) ("The provisions of [section 210] are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers.").

[11] 16 U.S.C.§ 824a-3(b); *see also* 16 U.S.C.§ 824a-3(d) (1988); 18 C.F.R. § 292.301(b)(6); *Connecticut Light and Power Company*, 70 FERC ¶ 61,012, at 61,023, 61,028, *reconsideration denied*, 71 FERC ¶ 61,035, at 61,151 (1995), *appeal dismissed*, 117 F.3d 1485 (D.C. Cir. 1997) (invalidating state QF rates that exceed avoided costs).

[12] S.C. Code Ann. § 58-41-20(A).

> the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[13]

This is precisely the same definition prescribed by the FERC's implementing regulations.[14] The definition of avoided cost, reflects PURPA's foundational requirement that purchasing QF power at the utility's avoided cost, if accurately quantified, ensures customers remain indifferent between the costs of utility or non-utility generation.

Q. PLEASE EXPOUND ON PURPA'S PRINCIPLE OF CUSTOMER INDIFFERENCE AND NONDISCRIMINATION FOR PURCHASES FROM QFs.

A. Section 210 of PURPA rests on the twin pillars of nondiscrimination and customer indifference. Specifically, Section 210 of PURPA requires that the price paid by utilities for "must take" purchases of QF output be "just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against qualifying co-generators or qualifying small power producers."[15] FERC has confirmed the need to ensure customer indifference to utility purchases of QF power, stating that, in enacting PURPA, "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives."[16] Thus, the "must purchase" obligation under PURPA requires utilities to offer to purchase QF power at "just and reasonable" rates that result in customer indifference as to

[13] S.C. Code Ann. § 58-41-10(2).
[14] 18 C.F.R. 292.101(b)(6).
[15] 16 U.S.C. § 824a–3; PURPA, Sec. 210(a) (2005).
[16] *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269 at p. 62,080 (1995), overruled on other grounds, *Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059 (2010).

whether the energy purchased is generated by the utility's generating fleet or purchased from the QF's generating facility pursuant to PURPA. Overall, these twin pillars promote fairness in the marketplace toward both QFs and the Companies' customers. In my view, setting avoided cost rates that achieve the customer indifference standard prescribed by PURPA also effectuates Act 62's requirement for the Commission to "treat small power producers on a fair and equal footing with electrical utility owned resources."[17]

Q. PLEASE DESCRIBE HOW THE COMPANIES INTERPRET THE DIRECTIVE FROM ACT 62 THAT REQUIRES THE COMMISSION'S DECISIONS STRIVE TO REDUCE THE RISK TO CONSUMERS.

A. Section 58-41-20(A) of Act 62 specifically provides that "[a]ny decisions" by the Commission addressing PURPA implementation in South Carolina must "strive to reduce the risk placed on the using and consuming public." This is a critically important objective for the Commission to consider as it reviews the Companies' updated avoided cost rates and policies under South Carolina's PURPA implementation framework set forth in the Act. In my view, this express policy directive requires the Commission to achieve the customer indifference and nondiscrimination objectives discussed above, while also minimizing the potential for future over-payment and reliability risks being imposed upon the Companies' customers that ultimately pay the costs of PURPA implementation.

[17] S.C. Code Ann. § 58-41-20(B).

Q. HAS FERC ISSUED NEW GUIDANCE ON PURPA RECENTLY?

A. Yes. On July 16, 2020, FERC issued Order No. 872[18], which updated FERC's regulations to provide state commissions tasked with implementing PURPA increased flexibility in establishing avoided cost rates for purchases of QF power. FERC revised its regulations implementing PURPA's mandatory purchase obligation "based on demonstrated changes in circumstances since [its] PURPA Regulations were first adopted to ensure that the regulations continue to comply with PURPA's statutory requirements established by Congress."[19] The Companies are continuing to evaluate how to incorporate the new options available under Order No. 872, in light of Act 62's prescriptive requirements for PURPA implementation in South Carolina, and may propose changes in accordance with Order No. 872 in future PURPA-related proceedings.

III. DESCRIPTION OF THE PEAKER METHODOLOGY USED TO CALCULATE AVOIDED COSTS UNDER PURPA

Q. WHAT METHODOLOGY DO DEC AND DEP USE TO CALCULATE AVOIDED COST UNDER PURPA?

A. DEC and DEP have consistently used the "peaker methodology" to forecast the Companies' avoided cost of capacity and energy in order to set the avoided cost rates paid to QFs.

[18] *See Qualifying Facility Rates and Requirements*, Order No. 872, 85 Fed. Reg. 54,638, 54,702 (July 16, 2020), 172 FERC P 61,041 (2020) ("Order No. 872"), *affirmed and clarified by* Order No. 872-A, 173 FERC ¶ 61,158 (Nov. 19, 2020).
[19] FERC Order No. 872, at P 20.

Q. PLEASE DESCRIBE HOW THE COMPANIES USE THE PEAKER METHODOLOGY TO CALCULATE AVOIDED COST.

A. The peaker methodology is designed to determine a utility's marginal capacity and marginal energy cost, and therefore, can be applied to quantify a utility's avoided costs for purposes of pricing power purchases from QFs. This approach assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine ("CT") generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF. Consistent with PURPA, the peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost. Importantly, avoided costs are calculated based on the rules, regulations and market conditions in place at the time the rates are calculated.

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN AVOIDED ENERGY COSTS AND AVOIDED CAPACITY COSTS UNDER THE PEAKER METHODOLOGY.

A. Avoided energy costs represent an estimate of the system's marginal variable operating costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt hour ("$/MWh"), include items such as avoided fuel, avoided variable environmental costs and avoided variable operations and maintenance ("VOM") costs. The peaker methodology approximates a utility's avoided energy cost through estimates produced by generation production cost modeling. Avoided capacity costs, on the other hand, represent fixed costs associated with the construction, financing and staffing of a CT facility. These fixed costs are not dependent on the actual use of the CT but rather the costs to build the CT and have it available to meet customer demand. As an analogy, if one was to purchase an electric vehicle, the avoided gasoline and avoided oil changes of a gas-powered vehicle would be the equivalent of avoided energy costs, which include avoided fuel costs and VOM. In addition, to the extent the electric vehicle offsets the purchase of a gas-powered vehicle, the car payment for the gas-powered vehicle would represent the fixed cost being avoided in the capacity payment and would be the equivalent of the avoided capacity cost.

Q. DOES THE PEAKER METHODOLOGY ALLOW THE COMPANIES TO FAIRLY AND APPROPRIATELY CAPTURE AND ESTIMATE THEIR AVOIDED COSTS THAT WOULD HAVE OTHERWISE BEEN INCURRED BUT FOR THE PURCHASE FROM THE QF?

A. Yes. The peaker methodology provides an appropriate and reasonable estimate of the avoided or incremental costs of alternative capacity and energy that would have otherwise been incurred but for the purchase from a QF facility. Importantly, it appropriately captures all avoidable marginal capacity and energy costs (or avoidable capital and operating costs) that consumers would otherwise pay "but for" the purchase from the QF. As such, the peaker methodology appropriately leaves the consumer indifferent to the utility's required purchase of QF generation relative to the utility's own generation.

Q. IS THE PEAKER METHOD A WIDELY-ACCEPTED METHODOLOGY IN THE UTILITY INDUSTRY FOR CALCULATING AVOIDED COSTS?

A. Yes. The Commission has consistently accepted the Companies' use of the peaker methodology to quantify DEC's and DEP's forecasted avoided capacity and energy costs. Specifically, in 2019, the Commission found that the peaker methodology is "a reasonable and appropriate methodology to fully and accurately quantify DEC's and DEP's forecasted capacity and energy cost to be avoided by purchases from QFs."[20] The Companies have also consistently utilized the peaker methodology in North Carolina, with the North Carolina Utilities Commission ("NCUC") finding that the peaker methodology is "generally accepted throughout the electric industry to calculate avoided costs."[21] The National Association of Regulatory Utility Commissioners ("NARUC") has also recognized the peaker methodology as one of the "dominant methodologies for measuring avoided cost under PURPA," which NARUC has further characterized as "well-developed for some time."[22]

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[20] Order No. 2019-881(A), at 29.

[21] *See Order Setting Avoided Cost Inputs*, at 30, NCUC Docket No. E-100, Sub 140 (Dec. 31, 2014) (Stating that the NCUC "has long approved the use of the peaker method for the purpose of establishing avoided costs and has repeatedly held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided cost.").

[22] Technical Conference on Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, *The Honorable Travis Kavulla President, National Association of Regulatory Utility Commissioners, and Vice Chairman, Montana Public Service Commission June 29, 2016*, FERC Docket No. AD16-16-000 (2016) (citing to Robert E. Burns & Ken Rose, "PURPA Title II Compliance Manual" (March 2014) ("PURPA Title II Compliance Manual"), available online at: https://pubs.naruc.org/pub/B5B60741-CD40-7598-06EC-F63DF7BB12DC).

Q. DO THE COMPANIES RECOMMEND THE COMMISSION APPROVE THE CONTINUED USE OF THE PEAKER METHODOLOGY TO CALCULATE DEC'S AND DEP'S AVOIDED CAPACITY AND ENERGY COSTS?

A. Yes.

IV. AVOIDED CAPACITY COST CALCULATION AND RATE DESIGN METHODOLOGY

Q. IN GENERAL TERMS, HOW ARE AVOIDED CAPACITY COSTS CALCULATED UNDER THE PEAKER METHODOLOGY?

A. The peaker methodology credits avoided capacity value to the QF based on the value created from avoiding a marginal peaking resource. As I noted in the analogy of the QF as an electric vehicle, the avoided capacity cost is the annual car payment for the avoided gas-powered vehicle along with other fixed costs such as taxes. To arrive at an avoided capacity rate involves the following general steps described in more detail later in my testimony.

1. The utilities' cost to construct a simple-cycle CT is calculated. These costs represent the fixed capital, financing and fixed operating costs associated with the construction and operation of a CT facility.
2. The fixed investment costs are converted to an annual cost that includes both the recovery-of and return-on the investment in the CT, along with the annual fixed operating costs, such as staffing.
3. The capacity values are increased by a Performance Adjustment Factor ("PAF") to put the QF on an equivalent basis to account for a certain level of forced

outages on the utilities' systems. Line losses and other upward adjustments are also made in this step of the process to get to the annual capacity cost.

4. A determination of when capacity is first needed on each of the utilities' systems is made to ensure the capacity rate calculation includes value for capacity at the time when each system has an actual capacity need.
5. The annual value of capacity is allocated between peak winter and summer seasons based on when seasonal capacity is required for system reliability. At this step, the avoided capacity value is expressed as a $/kW value for the winter season and a $/kW value for the summer season.
6. Finally, the winter and summer seasonal capacity values are then spread to the eligible capacity payment hours, which were evaluated to be the hours when capacity needs are the greatest (as defined in Schedule PP and the Large QF Tariff). The resulting avoided capacity rates are expressed in cents per kilowatt-hour ("cents/kWh"), as shown in the Companies' applicable tariffs.

Q. HOW DID THE COMPANIES CALCULATE THE ANNUAL AVOIDED CAPACITY VALUE OF A CT FOR PURPOSES OF DETERMINING THE AVOIDED CAPACITY VALUE TO BE PROVIDED BY A QF?

A. DEC and DEP each calculated their respective avoided capacity cost based on the cost of constructing combustion turbine capacity. Data from the Energy Information Administration ("EIA") was used as the basis for developing the CT capital cost.[23] The EIA data reflects the cost to build a single CT unit at a greenfield

[23] *See* U.S. Energy Information Administration, *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021* (February 2021), *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf (last visited May 17, 2021).

site. Given that the Companies' practice is to build multiple units at a new site, the Companies adjusted the EIA data to reflect the economies of scale associated with land, earthwork, buildings, roads, security, storage tanks and other infrastructure for a 4-unit CT site.

Q. PLEASE EXPLAIN WHY A PERFORMANCE ADJUSTMENT FACTOR, OR "PAF," IS RECOGNIZED IN THE AVOIDED CAPACITY CALCULATION.

A. Given that the utility's avoided fleet resources are occasionally unavailable, it necessarily follows that QFs replacing those resources should not be penalized for experiencing the same level of unavailability typically experienced by the resources it is displacing. The PAF is a simple reliability equivalence multiplier that is included in the avoided capacity rates paid by the Companies' customers to QFs. This multiplier increases the avoided capacity rate paid by customers and received by the QF. The Companies included a 1.07 PAF for DEC and 1.08 for DEP in the avoided capacity calculations as an adjustment to reflect the reliability equivalence of the Companies' respective generation fleets. For example, if the avoided capacity rate is $30/MWh, applying a PAF of 1.07 would increase the rate to $32.10/MWh, or increasing the amount paid to the QF for capacity by 7%. The Companies' inclusion of a PAF in calculating avoided capacity value is an example of how the Companies' application of the peaker methodology treats QFs on fair and equal footing with utility-owned resources, as contemplated by Act 62.

Q. HOW DOES THE TIMING OF THE UTILITIES' NEED FOR INCREMENTAL GENERATING CAPACITY IMPACT THE CALCULATION OF THE AVOIDED CAPACITY PAYMENT?

A. As a central tenet of PURPA, customers should not be required to pay QFs for avoided capacity unless the QF is actually offsetting a capacity need of the utility. PURPA's clear intent is to estimate the costs that, but for purchase from the QF, would have otherwise been incurred by the utility and its customers. Accordingly, the annual fixed capacity costs used in the avoided cost rate calculation includes the annual fixed capacity costs starting with the first year in which an actual avoidable capacity need exists, as determined by the utilities' IRPs.

Prior to the year in which the next avoidable generation unit is needed, the utility does not have a capacity need to avoid, and therefore in the calculation of the capacity rate, no value for avoided capacity is ascribed in these years. If this was not accounted for, customers would be paying a QF for marginal capacity that is providing no actual benefit to serve their needs for capacity.

Q. IN WHAT YEARS DO THE COMPANIES' INTEGRATED RESOURCE PLANS IDENTIFY THE FIRST AVOIDABLE CAPACITY NEED?

A. As described in detail in Chapter 13 of their respective 2020 IRPs, DEC's projection of its first avoidable capacity need arises in 2026, while DEP's first avoidable capacity need is 2024.[24] For comparison, DEC's first year of need (2026) is the same year of need as identified in the 2019 Avoided Cost Proceeding, which

[24] *See* Duke Energy Carolinas, LLC 2020 Integrated Resource Plan, at 113, Docket No. 2019-224-E (filed Sept. 1, 2020) ("DEC 2020 IRP"); Duke Energy Progress, LLC 2020 Integrated Resource Plan, at 113, Docket No. 2019-225-E (filed Sept. 1, 2020) ("DEP 2020 IRP").

results in an increase to the avoided capacity rates relative to the 2019 proposed avoided capacity rates. This increase is due to the fact that the number of years in the updated 10-year period with an ascribed capacity value has increased by two years since 2019. DEP's identified first year of need (2024) arises four years later than that the first year of need identified in the 2019 Avoided Cost Proceeding, which results in a decrease to the avoided capacity rates relative to the 2019 proposed avoided cost rates.

Q. IF A UTILITY'S NEXT AVOIDED CAPACITY NEED IS SEVERAL YEARS IN THE FUTURE, WHEN DOES THE QF BEGIN RECEIVING A CAPACITY PAYMENT?

A. Under the levelized rate design, the avoided capacity payments are levelized to allow the QF to receive an avoided capacity payment in each year of the contract, as long as an actual capacity need exists at some point within the term of the avoided cost period. More precisely, the QF will receive a levelized capacity rate that takes into account a zero value of capacity in the initial years prior to the utility's first avoidable capacity need, as well as an avoidable capacity value in all subsequent years of the avoided cost period. Put another way, the QF will receive capacity payments during each year of the contract, in order to credit the QF for the future avoided capacity, so long as the utility has an avoidable capacity need within the avoided cost period.

Q. IS RECOGNITION OF DEC's AND DEP's NEED FOR CAPACITY IN THIS CALCULATION FAIR TO THE COMPANIES' CUSTOMERS AND TO QFs?

A. Yes, the Companies' customers only pay capacity payments to the QF that are equal to the economic value of the utility's actual avoided capacity cost. This approach is also fair and non-discriminatory to QFs.

Q. PLEASE DESCRIBE THE SEASONAL ALLOCATION WEIGHTING THAT IS INCLUDED IN THE DETERMINATION OF THE AVOIDED CAPACITY PAYMENTS.

A. Seasonal allocation places capacity value into the appropriate season of the year that drives the Companies' reliability need for new capacity resource additions. For DEC and DEP, seasonal allocation is heavily weighted to winter based on the impact of summer versus winter loss of load risk, which has been driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. Consistent with Order No. 2019-881(A),[25] the Companies have developed the seasonal allocation factors based on total connected solar generating facilities plus solar facilities with signed PPAs.[26] In accordance with this analysis, DEP's avoided capacity rates pay all of the annual capacity value in the winter while DEC's avoided capacity rates pay 89% of the annual capacity value in the winter and the remaining 11% in the summer period.

[25] Order No. 2019-881(A), at 112-113.

Q. PLEASE DESCRIBE THE METHODOLOGY THE COMPANIES USE TO PAY QFs FOR CAPACITY VALUE.

A. With respect to QF rates, the Companies recognize that traditional methods of paying for dispatchable capacity based on deliverability requirements with after-the-fact adjustments for actual unit performance, are particularly problematic for smaller intermittent QF resources. To overcome these deliverability challenges and the lack of QF dispatchability, the Companies' QF capacity rates are paid on a per-kWh basis across a pre-determined set of seasonal hours that represent the hours most likely to have capacity value. Paying QFs for capacity on a per-kWh basis is consistent with the approach the Companies have historically utilized with respect to QF rate design.

Q. PLEASE IDENTIFY THE SPECIFIC HOURS WHEN QFs WILL PROVIDE CAPACITY VALUE.

A. The Companies' capacity rate design offers distinct pricing periods to accurately reflect the marginal capacity value to customers during each capacity period. The pricing periods are updated based on loss of load risk identified in the 2020 Resource Adequacy Study conducted by Astrapé Consulting, LLC for DEC and DEP (which was included as Attachment III to the Companies' 2020 IRPs). For DEC, the pricing periods offer capacity payments during the PM hours in the summer months of July and August and AM hours in the winter months of December through March. For DEP, the pricing periods offer capacity payments during the AM hours in the winter months of December through March. The hourly capacity pricing periods differ slightly between DEC and DEP and are shown in **Snider DEC/DEP Exhibit 3**. These pricing periods represent the hours of capacity need and thus reflect the value of QF capacity to ensure customers are paying for QF capacity that actually reduces the Companies' needs for future capacity.

Q. DOES THE COMPANIES' AVOIDED CAPACITY PAYMENT RATE DESIGN PROVIDE APPROPRIATE PRICE SIGNALS TO ENCOURAGE QF DEVELOPMENT AND APPROPRIATELY PAY QFs FOR THE CAPACITY VALUE THAT THEY PROVIDE?

A. Yes. The avoided capacity payment rate design provides appropriate price signals and incentivizes QFs to maximize output during times when capacity has the most value to the Companies' customers.

Q. IS THE COMPANIES' AVOIDED CAPACITY CALCULATION AND RATE DESIGN CONSISTENT WITH THE COMMISSION'S ORDERS IN THE 2019 AVOIDED COST PROCEEDING?

A. Yes, it is.

V. AVOIDED ENERGY COST CALCULATION AND RATE DESIGN METHODOLOGY

Q. IN GENERAL TERMS, HOW ARE AVOIDED ENERGY COSTS CALCULATED UNDER THE PEAKER METHODOLOGY?

A. In any given hour, a utility will have a variety of units online such as hydro-electric, nuclear, solar, natural gas combined-cycle, coal, natural gas simple-cycle CTs and diesel fuel oil CT resources. These units all have differing variable fuel and operating costs that are considered in order to dispatch them in economic merit order to meet the utility's instantaneous load obligations. To calculate the avoided marginal energy value, two production cost simulations are performed and then compared to each other to determine the value of QF energy. A production cost model simulates the generation commitment and dispatch of the utility's fleet of generating resources needed to meet the utility's load over the ten-year avoided cost period on an hour-to-hour basis. The first simulation uses IRP models and current market assumptions to establish the "base case" of the estimated variable production costs over the period. The second simulation is identical to the first but adds a hypothetical 100 MW of no-cost generation to the utility's generating fleet, which is available to the system in every hour of the ten-year period. Adding this hypothetical, no-cost generation to the simulation displaces energy from the marginal units that were operating in the "base case," and as a result, lowers the overall variable production costs relative to the base case. Comparing the hourly production cost associated with the base case relative to the second case with the 100 MW of no-cost generation determines the marginal hourly energy costs that can be avoided over the study period. These marginal avoided costs are then used to calculate the avoided energy rates that leave a customer indifferent between QF purchases and generation provided by the utility.

Q. PLEASE EXPAND ON HOW THE AVOIDED MARGINAL ENERGY COSTS ARE DERIVED.

A. Since the utility commits and dispatches its generation units in an economic merit order, comparing the base case production cost run previously described to the second case with 100 MW of no-cost generation results in the marginal variable production cost savings attributable to 100 MW of incremental no-cost generation. Compared to the base case simulation, the case with the 100 MW of no-cost generation will show savings resulting from reduced fuel consumption, reduced environmental allowance costs and reduced VOM costs. These nominal cost savings can then be converted to a dollar per MWh value by dividing the savings in any given time period by the product of the number of hours in that period multiplied by the 100 MW output of the unit. Once nominal avoided energy costs are determined over the ten-year avoided cost period, they are then levelized by time period to produce the avoided energy rate in cents per kWh.

Q. WHAT FACTORS INFLUENCE THE CALCULATION OF THE AVOIDED ENERGY COST RATES?

A. A number of factors that drive the avoided cost calculation change over time, including load and energy forecasts, resource mix, unit characteristics, VOM costs, environmental emissions costs, reagent costs and fuel costs. While updating items such as VOM costs, environmental reagent costs, and the relative efficiency of the marginal unit with the most current information all factor into the utility's marginal cost of generation, recent changes in the commodity market price for natural gas represents the most significant change impacting the Companies' avoided costs. This is because natural gas commodity prices represent the primary driver of the avoidable energy cost since a natural gas-fueled combined-cycle unit or combustion turbine unit is often the marginal resource.

Q. IS THE NATURAL GAS FORECASTING METHODOLOGY USED IN THIS PROCEEDING CONSISTENT WITH THE COMPANIES' 2020 IRPs AND THE COMMISSION'S ORDERS IN THE 2019 AVOIDED COST PROCEEDING?

A. Yes. This methodology is consistent with the Commission's orders in the 2019 Avoided Cost Proceeding[27] and is also consistent with the methodology used in the Companies' 2020 IRPs.

Q. PLEASE DESCRIBE THE COMPANIES' AVOIDED ENERGY RATE DESIGN.

A. The marginal energy rate structure includes differentiation of Summer, Winter and Shoulder seasons. The Summer energy season is defined to include June, July, August, and September; the Winter energy season is defined to include December, January, and February; and the Shoulder energy season is defined to include March, April, May, October, and November.

When developing the analytical support for the avoided cost pricing periods required by the Commission in Order No. 2019-881(A),[28] the Companies determined that the analysis supported certain adjustments to the pricing periods that were approved by the Commission in the 2019 Avoided Cost Proceeding. A comparison of the changes to the pricing periods was provided with the Companies' Application filed in this docket on April 22, 2021, and is also shown in **Snider DEC/DEP Exhibit 2**.

[27] Order No. 2019-881(A), at 29, 66.
[28] Order No. 2019-881(A), at 75.

For DEC, the rate design reflects ten energy pricing periods, and for DEP, the rate design reflects nine energy pricing periods, which reflect the energy value of QF generation during the different time periods. This rate design appropriately compensates QFs for the avoided energy value they create for customers through the incorporation of these granular seasonal and hourly rate periods. The energy pricing periods, and their respective prices are shown in **Snider DEC/DEP Exhibit 3**.

The hourly energy rate periods reflect the concept of including higher-priced periods, called premium peak hours, in the Companies' Winter and Summer seasons. These premium peak hours provide the highest energy rates within each season to incent generation during these hours when the value of the energy avoided by QF power is greatest for customers. Days with premium-peak and on-peak hours include Monday through Friday, excluding certain holidays. Off-peak hours within each season include all hours not otherwise defined as premium or on-peak, and include certain holidays. The hourly definitions for the pricing periods have some variation between DEC and DEP to account for the differences in each utility's load profile net of solar generation.

Q. DID THE COMPANIES INCLUDE A TRANSMISSION SYSTEM LINE LOSS CREDIT FOR QFs?

A. Yes. The Companies' avoided cost calculations continue to recognize distribution-connected QF generation's avoidance of transmission system line losses, and therefore, the tariff rates continue to include avoided energy and capacity line loss credits. The Companies also include an avoided loss factor for distribution- and transmission-connected QF generation to recognize the avoidance of generation step-up voltage losses.

Q. DO THE COMPANIES INCLUDE AVOIDED ENVIRONMENTAL COSTS IN THE DEVELOPMENT OF THE AVOIDED ENERGY COST RATES?

A. Yes. As mentioned previously, the Companies' avoided energy cost rates include avoided emission control reagents and allowance costs for sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") based upon the costs actually avoided by the Companies. Consistent with PURPA, the Companies have not included more speculative costs, such as avoided carbon dioxide ("CO_2") emission costs that are not actually being avoided by the utility.

Q. DO THE COMPANIES' AVOIDED ENERGY RATE DESIGNS PROVIDE APPROPRIATE PRICE SIGNALS TO ENCOURAGE QF DEVELOPMENT AND APPROPRIATELY PAY QFs FOR THE ENERGY VALUE THAT THEY PROVIDE?

A. Yes. The avoided energy payment rate designs provide sufficient seasonal and hourly granularity and appropriate price signals and incentives for QFs to maximize output during times when energy has the most value to the Companies and their customers.

Q. DOES THE COMPANIES' AVOIDED ENERGY CALCULATION AND RATE DESIGN MEET THE REQUIREMENTS OF THE COMMISSION'S ORDERS IN THE 2019 AVOIDED COST PROCEEDING?

A. Yes, it does.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.